Service Date: April 29, 1981

DEPARTMENT OF PUBLIC SERVICE REGULATION
MONTANA PUBLIC SERVICE COMMISSION

In the Matter of the Application of	)	UTILITY DIVISION
MONTANA-DAKOTA UTILITIES	)	
COMPANY to Adopt Increased Rates for	)	DOCKET NO. 80.7.52
Natural Gas Service in the State of	)	
Montana.	)	ORDER NO. 4784

APPEARANCES

FOR THE APPLICANT:

Joseph R. Maichel and Marilyn Foss, Attorneys at Law, 400 North 4th Street,-Bismarck, North Dakota 58501, appearing on behalf of Montana-Dakota Utilities Company

John Alke, Attorney at Law, Hughes, Bennett, Kellner and Sullivan,

406 Fuller Avenue, Helena, Montana 59624, appearing on behalf of Montana-Dakota Utilities Company

INTERVENORS:

James C. Paine, Montana Consumer Counsel, 34 West Sixth Avenue, Helena, Montana 59620, appearing on behalf of the consuming public of the State of Montana

John Allen, Consumer Counsel Staff Attorney, 34 West Sixth Avenue, Helena, Montana 59620, appearing on behalf of the consuming public of the State of Montana

Jerome Anderson, Attorney at Law, Anderson, Brown, Gerbase, Cebull and Jones, P. C., 100 Transwestern Building, Billings, Montana 59101, appearing on behalf of Pierce Packing Co., Midland Empire Packing Co., Midland Foods Distributing Co., and Midland Foods, Inc.

William C. Leaphart, Attorney at Law, 1 North Last Chance Gulch, Helena, Montana 59601, appearing on behalf of Great Western Sugar Company

FOR THE COMMISSION:

Eileen E. Shore, Staff Attorney

BEFORE:

GORDON E. BOLLINGER, Chairman
JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner
THOMAS J. SCHNEIDER, Commissioner

FINDINGS OF FACT

General

1. On July 25, 1980, Montana-Dakota Utilities Co., Applicant, filed with the Montana Public Service Commission an Application for Authority to Increase Rates for Natural Gas Service in the state of Montana. The rates is designed to generate additional annual requested increase in revenues in the amount of $4,518,142. The additional revenue represents a in rates to industrial and commercial interruptible 12.77 percent increase customers and a 12.56 percent increase in rates to residential and firm in a weighted-average Montana system commercial customers resulting increase of 12.61 percent.

2. Pursuant to receipt of the Application, the Commission on September 22, 1980, issued a Procedural Order outlining the procedure to be followed in this Docket.

3. On December 16, 1980 the Commission issued a Notice of Public Hearing on the application to adopt increased rates ,or natural gas service in Montana. On January 2, 1981 the Notice of Public Hearing was amended to reflect a change in the hearing dates.

4. The hearing was held beginning at 10:00 a.m. on January 22, 1981 in Judge Battin's Courtroom, Federal Building, U.S. Courthouse, 316 North 26th Street, Billings, Montana. A special session was held beginning at 7:00 p.m. on the evening of the 22nd to take testimony from witnesses from the general public. The hearing was concluded on January 23, 1981 at 4:00 p.m.

5. The test year in this matter is the year ending December 32, 1979.

6. The Application applies solely to the gas operations of Montana-Dakota Utilities.

7. On September 26, 1980 Montana-Dakota Utilities filed with the Commission a petition seeking authority to enter into a transaction for the purpose of financing the acquisition and storage of natural gas (the Frontier project) .

Approval of the aforementioned transaction would significantly affect the present Application in that the result would be to exclude from rate base a significant portion of natural gas stored underground and eliminate some of the expenses associated therewith.

8. On March 10, 1981 the Commission provided MDU the authority to implement the Frontier transaction.

Rate of Return

Capital Structure

9. The Applicant, through witness J. F. Renner, proposed the following capital structure for MDU's gas utility:

	Amount (OOO's)	Ratio
Long-Term Debt	$ 73,594	47.04%
Preferred Stock	22,469	14.36
Common Equity	60,393	38.60
	$156,456	100.00%

10. The above amounts include prose, or total, year-end plant invest-

ment, construction work in progress and the noncurrent portion of gas in underground storage. The allocation factor using this criterion is computed to be 45.3 percent.

11. The Montana Consumer Counsel, through the testimony of expert witness Caroline M. Smith, proposes the following capital structure:

	Amount (OOO's)	Ratio	
Long-Term Debt	$ 86,903	47.8%	
Preferred Stock	22,715	12.5	
Common Equity	72,046	39.7	$181,664
	100.00%		

12 . The allocation factor offered by witness Smith (.46358) is developed using the criterion of common and-utility plant in service at June 30, 1980. Because it is based on plant in service the Commission accepts the allocation factor of .46358.

13. Applicant's witness Renner and MCC witness Smith both include $30,457,000 of REA Mortgage Notes and Pollution Control Bonds in the amount of long-term debt outstanding although Mr. Renner acknowledges that this debt applies only to the electric utility. (J . F . Renner, Direct, p . 6) If the Commission finds it appropriate to remove this debt from the total outstanding long-term debt applicable to the gas utility.

14. In addition, Dr. Smith has added $25,000,000 of debt at an imputed cost of 12.5 percent to the MCC proposed capital structure. However, as Applicant's witness Glynn has pointed out, neither has the Company issued the bonds nor is it possible to determine a priori at what cost the bonds will be issued. (W.C. Glynn, Rebuttal, p. 7) The Commission, adhering to its policy of limiting adjustments to known and measurable changes, finds this adjustment inappropriate.

15. Removing the $30,467,000 of REA Mortgage Notes and Pollution Control Bonds from the proposed capital structures of both the Applicant and the Montana Consumer Counsel, and removing the additional $25,000,000 imputed to the capital structure proposed by the MCC, reduces the amount of outstanding long-term debt in both capital structures to $131,933,000. The Commission finds this latter amount to be the correct amount of outstanding long-term debt for the Company. Applying the allocation factor of .46358 to this amount yields $61,189,000 of long-term debt applicable to the gas utility.

16. Applicant's witness Renner has computed the Company's outstanding amount of preferred stock to be $49,600,000. This is arrived at by adding to the December 31, 1979 balance of $35,000,000 the planned issuance of $15 000.000 of referred stock and subtracting the mandatory annual MCC witness Smith has determined the outstanding redemption of $400,000. amount of preferred stock to be $49,000,000. In arriving at this amount, Dr. Smith references Applicant's prefiled Exhibit E-3, but provides no explanation for the minor discrepancy. The Commission accepts the amount of $49,600,000 as the correct amount of outstanding preferred stock for the Company . Applying the allocation factor of .46358 to this amount yields $22,994,000 of preferred stock allocated to the gas utility.

17. Total utility common equity at September 30, 1980 is projected to be $133,319,000 by Mr. Renner. Dr. - Smith, in referencing the Company's September 30, 1980 Form 10Q, has indicated that actual total utility common equity is $156,163,000. This amount, when reduced by $750,000 of Subsidiary Investments and then multiplied by the gas allocation factor, results in $72,046,000 of common equity allocated to the gas utility operations. Since this latter figure is based on actual amounts outstanding at September 30, 1980 The Commission finds this figure to be the appropriate amount of outstanding common equity applicable to the gas utility.

18. The appropriate capital structure is:

	Amount (000's)	Ratio

Long-Term Debt	$ 61,189	39.17%
Preferred Stock	22,994	14.72
Common Equity	72,046	46.11
	$156,229	100.00%

Cost of Debt

19. The cost of debt is not an issue in this case. The Applicant and the Consumer Counsel are in agreement that this cost is 8.508 percent. This cost is determined by weighing the cost of the Company's Serial Bonds

and Sinking Fund Bonds and considering Sinking Fund Redemptions to September 30, 1980.

Cost of Preferred Stock

20. As was the case with the cost of debt, the Applicant and the Consumer Counsel agreed, in testimony filed prior to the hearing, upon the same cost for preferred stock. The cost is 7.912 percent, based on the December 31, 1979 balance and a proposed August, 1980 issue of $15,000,000 at 10.5 percent. However, based on the response of Applicant's witness Glynn during cross-examination at the hearing, the Commission finds it necessary to modify the cost of preferred stock. As witness Glynn stated during cross-examination, the planned August issue was not issued until December and was issued at a cost of 10.25 percent rather than 10.50 percent. (Tr., p. 118). The Commission, using an issuance expense of 3/8 of one percent, determines the cost of preferred stock to be 7.791 percent calculated as follows:

Preferred Stock

	Outstanding 9/30/80 (000's)	Annual Cost	Adjusted Embedded Cost
Balance December 31, 1979			
December, 1980 Issue	$35 000	$2,365,536	6.759%
Amount	15,000		

Annual Dividend Rate	(10.25%)		
Annual Carrying Cost	(10.29%)	1,543,500	
Annual Redemption	(400)	(44,9l2)	
	49,600	$3,864,124	7.791%

Cost of Common Equity
Applicant

21. Applicant's witness Dr. Dennis B. Fitzpatrick, an independent financial consultant, presented testimony pertaining to the Company's cost of common equity capital. In his analysis Dr. Fitzpatrick examined the U. S. money and capital markets and provided both a comparable earnings and a discounted cash flow (DCF)- study. The results of his analysis indicate that the cost of MDU's previously issued common equity lies in the range of 14. 00-14.25 percent; when adjusted for underwriting and market pressure costs this range becomes 14.66-14.91 percent.

22. Mr. Fitzpatrick's comparable earnings analysis is based on four samples of companies displaying risk characteristics similar to risks associated with MDU's gas and electric utility operations. The first sample consists of relatively small combination gas/electric utilities. These companies are purported to have operating and business risks similar to these of MDU.

Sample two consists of all electric and gas distribution companies having a Value Line Beta of .65, MDU's Value Line Beta. The Beta Coefficient is a measure of stock price volatility relative to the market as a whole. Gas and electric utilities generally have Beta values less than 1.00, indicating a greater stability in the prices for stocks of these firms than in overall market prices. This is consistent with the notion that utility stocks are generally considered to be income rather than growth stocks.

Sample three includes all electric utilities that have a Salomon Brothers' Earnings Quality Rating cf B-, MDU's EQR, and sample four consists of all natural gas distribution utilities surveyed by the Value Line Investment Survey.

23. The average return on common equity for each of the samples or the years

1970-1979 is presented on Schedules D . B . F . -21, D . B . F . -27, D . B . F . -33 and D . B . F . -39 of MDU Exhibit No. 19 . Examination of the schedules indicates that rate of return performance for each of the samples has been relatively stable over the last ten years with returns falling in the 13-13 percent range. As the schedules exhibit, MDU's return also has fallen in the .1-13 percent range over the last ten years. A closer examination reveals that MDU's average return for the years 1970-1979 is generally slightly higher than the average returns of the four samples over the same time period.

24. Dr. Fitzpatrick's Discounted Cash Flow (DCF) analysis is based on the fundamental proposition that for any company the cost of common equity capital is equal to that rate of return that equates the present value of the expected dividend stream with the actual market price of the stock. This proposition can be translated into the familiar equation:

$$ke = d1/Po + g$$

where ke = the cost of common equity
d1 = the dividend to be received in year one
Po = the market price of the stock, and
g = the investors expected dividend growth rate.

It becomes the job of the analyst to determine the stock's dividend yield (d1/Po) and estimate the dividend growth rate (g) expected by investors.

25. Dr. Fitzpatrick provides the results of applying the DCF analysis to MDU alone and to each of the four samples of companies used in the comparable earnings analysis. These results are summarized on Schedules D.B.F.-44 through D.B.F.-48 of MDU Exhibit No. 19. The dividend yields utilized by Dr. Fitzpatrick are spot yields for June 3, 1980. Estimates of the dividend growth rates come from "implied dividend growth rates" and average tangible book value growth rates for the time periods 1970-1979, 1975-1979, and 1979. Dr. Fitzpatrick suggests that use of these different growth rate estimates produces a range of future dividend growth rates that investors can reasonably expect to be forth coming.

The "implied dividend growth rate" assumes a constant return on common equity and dividend payout ratio over time. This assumption provides for a constant dividend growth rate (an assumption underlying all DCF analyses) equal to the return on common equity times the earnings retention ratio, where the earnings retention ratio is one minus the dividend payout ratio.

Tangible book value growth rates are employed on the argument that cash dividend growth rates are dependent on the growth of the firm's underlying earnings, and that book value gross rates are relatively good indicators of future growth in earnings.

26. Dr. Fitzpatrick's DCF analysis provides a range of values from 13.00-15 .9 percent for the return on common equity. He concludes that MDU's cost of previously issued common equity is in the 14.00-14.25 percent range :

27. Schedules D. B . F. -49, D. B. F.-50 and D. B . F . -51 of MDU Exhibit No. 19 present market pressure and underwriting costs associated with MDU's common equity securities. Dr. Fitzpatrick calculates average underwriting costs - to be 4.405 percent and average market pressure costs to be 2.375 percent- for total issuance costs of 6.78 percent. He concludes that the cost to MDU of issuing new securities is in the range of 14.66-14.91 percent after making the adjustment for the issuance costs (Schedule D.B.F.-2, MDU Exhibit No. 19).

28. In prefiled supplemental testimony Dr. Fitzpatrick updates his DCF analysis to reflect dividend yields for the last quarter of 1980. On the basis of the results of the updated analysis, Dr. Fitzpatrick concludes that the cost of new common equity is in the 15.52-16.02 percent range. No adjustment was made to reflect any change in the expected dividend growth rate. The Commission notes that the Applicant has based its requested rate of return on Dr. Fitzpatrick's initial analysis rather than his supplemental testimony.

Montana Consumer Counsel .

29. The Montana Consumer Counsel, through the expert witness testimony of Dr. Caroline M. Smith, has recommended a rate of return on common equity of 13.5 percent for MDU's cost - of common .equity capital associated with gas operations.

Although Dr. Smith also presents a comparable earnings and a DCF analysis, she- considers the comparable earnings analysis to be of limited usefulness and places the thrust of her argument in an extended, statistical DCF model designed to take account of intra-industry risk differentials.

30. Dr. Smith uses the ninety-hour electric and common Utility companies traded on the New York Stock Exchange for one sample of comparable companies used in her comparable earnings analysis. She notes that over the 1970-1979 period these companies have experienced average earnings on common equity in the 11-13 percent range. (Schedule CMS-4 of MCC
Exhibit B.)

31. Schedule CMS-5 of MCC Exhibit B illustrates that earned equity returns for gas distribution utilities are in the 10.7-12.4 percent range for the period 1970-1979.
32. Schedule CMS-6 of MCC Exhibit B illustrates that o! the 1,351 companies carried in the Value Line data base those having Beta values similar to Beta values for utilities earned returns in the 11.89-12.01 percent range in 1978 and earned returns in the 13.99-14.26 percent range in 1979.

33. On the basis of her comparable earnings analysis Dr. Smith concludes that a return of 13.00-13.50 percent on common equity is reasonable when compared to earnings of companies whose risk is comparable to MDU's common stock.

34. Dr. Smith's DCF analysis is based on a statistical model that relates a particular company's cost of common equity capital to the industry average dividend yield, the industry average expected dividend growth rate, the individual company's dividend yield and the individual company's historical growth rate. The model is designed to take into account intra-industry risk differentials. This differential is defined to be the difference between the individual company's actual dividend yield and the individual company's predicted dividend yield, which is a statistically estimated value that is a function of the industry average expected dividend growth rate and the individual company's historical growth rate.

In this manner the return for a particular individual firm can be considered within the framework of the entire industry. Dr. Smith argues that this approach is logical because the rational investor does not base his evaluations on the past performance of a single firm but on expectations generated within the industry, as these latter expectations tend to dilute the extreme situations ' that individual firms are often subjected to.

35. The industry in Dr. Smith's model is represented by the ninety-four electric and combination utility companies traded on the New York Stock Exchange.

36. The results of Dr. Smith's DCF analysis indicate that while the industry average cost of common equity is estimated to be 14.3 percent, the cost of common equity for MDU is 13.00 percent. The 130 basis points difference is representative of the intra-industry risk differential associated with MDU when that company is viewed within the context of the entire industry.

37. Before arriving at her recommended cost of common equity of 13.5 percent Dr. Smith considers certain circumstances particular to MDU:

Q. Are there also circumstances unique to MDU which prohibit the use of current market data in estimating the cost of common equity to the company?

A. Yes, there are. In 1979, about half of the Company's net income was provided by non-utility operations. This contribution of non-utility earnings has been substantial for the past few years, and is a clear signal- to investors that future earnings will be derived from sources, other than the low risk electric and gas operations. The Company's dividend yield is well below the industry average, and that indicates that dividend growth expectations for the Company as a whole into the long-term future are higher than historical data would suggest. MDU relies primarily upon coal burning facilities for electric power generation, and both coal and a small portion of the gas supply are supplied to the Company by its own subsidiaries. Moreover, unlike most companies in the electric power industry, MDU has no nuclear generation facilities and has- not announced future nuclear construction. Furthermore, the Montana Commission permits the Company quick recovery of externally controlled gas prices through a cost tracking procedure. This means that MDU's cost of equity capital is somewhat higher than the 13 percent DCF results of my statistical model, and is at the upper end of the 12 to 14 percent range which reflects the current uncertainty about the continuation of historical growth rates. Gas distribution companies tend to have an equity cost somewhat above the cost of equity capital to electric utilities, although Montana's cost tracking procedure offsets this difference to some extent. Taking all of these factors into account, my equity cost estimate for MDU's gas operations is 13.5 percent. (Smith, Direct, pp. 20,21)

38. Dr. Smith, while recognizing the legitimacy of underwriting costs, makes no explicit adjustment for them. Neither is an adjustment made for market pressure costs. Dr. Smith instead presents evidence indicating the inappropriateness in making adjustments for market pressure costs:

Q. What is the basis for your conclusion that no market pressure adjustment is warranted?

A. First of all, the price effects of experienced market pressure are already largely accounted for in the DCF model. Moreover, as the economic theory of security market behavior and portfolio analysis has developed in recent years, attention has been drawn to the proposition that securities issued by different companies are very close substitutes for one another, so long as the price of these securities reflects differences in risk and in expected returns. If this proposition about securities is valid, then an increase in the number of outstanding she. es of the stock of any one company will have little or no measurable effect on the price of that security. The reason is that the increase in the supply of that one security is a drop in the bucket compared to the total outstanding quantity of highly substitutable securities; and therefore essentially no price concession is required to induce investors to hold additional quantities of the stock of the issuing company.

Q. Is there empirical support for this proposition?
A. A study of the behavior of securities markets, designed precisely to test the validity of this proposition, has been performed by Myron S. Scholes and published in the 1972 Journal of Business. This study supports the proposition that market pressure is negligible.

The Scholes study provides important support to the - general proposition that common equities are highly substitutable, and therefore that an offering of stock in any one company will have little or no measurable effect on the price of that company's common stock. However, the Scholes study does not relate specifically to the current circumstances of the utility industry. Rather, it is an investigator of secondary common stock offerings during the entire post-war period, through the mid-1960's. Nevertheless, I believe that this study is one valid test of the general proposition that market pressure is insignificant; and that the findings presented there a. e properly applicable to the utility industry in the present economic circumstances. However, to. confirm the applicability of this study to the utility industry at the present time, I have reviewed additional data and made further analyses pertaining specifically to security offerings by utilities in recent years. - (Smith, Direct, pp. 26-28)

39. Further empirical support for the proposition that it is not appropriate to adjust for market pressure is presented in Schedule CMS-8 in MDU Exhibit B. That schedule provides persuasive evidence indicating the random nature of the likelihood of market pressure being neither positive or negative. Dr. Smith concludes that market pressure effects cannot be built into the return requirement.

Commission Analysis

40. The Commission finds Dr. Fitzpatrick's -recommendation of 14. 25 percent for the cost of common equity capital unconvincing for several reasons. A

significant reason for concern on the part of the Commission is Dr. Fitzpatrick's use of a spot yield for the dividend yield. In unregulated markets where prices are free to fluctuate and consumers face alternatives, spot yields are appropriate. However, the regulator, in determining an appropriate cost of capital must consider not just a point in time but the entire period of time during which the established rates will be in effect. Although the cost of capital may change from day to day, a single rate may be in effect for at least a year, and more often longer. To set the cost of common equity at a rate prescribed by a single point in time during which inflation rates may be inordinately high, and to- allow- that rate to remain in effect over an extended subsequent period of time that will more than likely reflect more normal market conditions, would result in an injustice to the ratepayer.

41. Secondly, as Dr. Smith points out, the use of an "Implied Dividend Growth Rate" that assumes a constant return on common equity and dividend payout ratio compounds the spot price yield problem:

Under Dr. Fitzpatrick's calculation method, the growth estimate is a fixed value and bears no relationship to investor expectations. The selection of a three, five and ten-year book value growth period is arbitrary, and the use of a least-squares calculation for a three and even seven-year period is inappropriate. The implied growth rate is also flawed, although mathematically, growth is return times retention rate. However, the DCF requires an estimate of the growth investors expect; Dr. Fitzpatrick's formula will not produce that quantity unless expected returns and expected retention rates are used in the calculation. Dr. Fitzpatrick's selection of data in this regard also appears arbitrary. For example, he uses single one-year return and retention history, bu t a three-year period of historical book value growth.

The fact that the growth rate calculation produces a value which does not change with changing market prices (although Dr. Fitzpatrick appears to recognize the relationship between growth expectations and market prices) and spot yields fluctuate constantly means that Dr. Fitzpatrick's results depend quite literally on the day of the week his analysis is completed. Such results offer the Commission no solid evidence concerning the appropriate cost of equity for ratemaking purposes. (Smith, Direct, pp. 23,24) 14.72

42. As regards Dr. Fitzpatrick's Supplemental Testimony, the Commission finds the adjustments made therein inappropriate and cannot accept the argument. In that the cost of common equity for a particular time period is composed of two parts, the dividend yield and the expected growth rate of dividends, the Commission finds it theoretically unsound to adjust one component while allowing the other component, based on a prior analysis, to remain unadjusted, as Dr. Fitzpatrick has done in his Supplemental filing. As Dr. Smith points out during cross-examination on the issue:

In conjunction with that, when Dr. Fitzpatrick updated his testimony, he kept the growth rates exactly the same although the dividend yields changed markedly. Growth and dividend yields are inversely related to each other. That is, when investors believe that growth is- going to be lower than they thought previously, they tend to price stock so the dividend yields are higher and vice-versa. (Tr. p. 306)

43. The Commission finds Dr. Smith's recommendation of 13.00 percent to be a reasonable cost of common equity for MDU's previously issued common stock. The concept of a DCF model that explicitly considers intra industry risk differentials is not only theoretically appealing but comports with the notion that the rational investor considers forces external to the individual firm in formulating his risk/return expectations. Sufficient evidence has also been presented to justify making' no adjustment for market pressure costs. Notwithstanding the fact that MDU has experienced positive market pressure costs in its last two issuances;, the random nature of these costs does not allow the assumption' that these costs will continue to be positive in the future.

44. The one-half percentage point adjustment made by Dr. Smith in consideration of those characteristics peculiar to MDU is also sufficient to cover underwriting expenses associated with future offerings. The Commission finds 13.5 percent to be a reasonable cost of common equity for MDU at this time.

An integral component of the risk/return relationship characteristic of the Company lies in the nature of the gas cost tracking procedure faced by the Company. Commission Order No. 4742a, stemming from the Applicant's last gas cost tracking applicator, expresses the Commission's attitude on this issue:

It remains the intent of this Commission to devise and adopt a tracking procedure that equitably and expeditiously provides for the pass-through of rising gas costs due to the Natural Gas Policy Act of 1978. In the advent of a tracking procedure designed to satisfactorily meet the goals of equity and expedition the Commission intends to adopt an interim rate approval policy that would place new rates stemming from a tracking application into effect within ten (10) days of the hearing date of such application.

Examination of -Schedule J-1, of Applicant's Exhibit No. 19, reveals that under the Applicant's pro forma operating income and rate of return reflecting additional revenue requirements, the cost of gas component is by far the largest single component making up the revenue requirement, being forty-seven (47) percent of revenue requirements. This fact, coupled with the Commission's attitude regarding tracking, acts to significantly reduce the risk associated with recoupment of the Applicant's required revenues.

Acting to reduce the Company's risk even further is the fact that the carrying costs associated with the financing of gas placed in storage via the Frontier transaction are flowed through immediately as pa. t of the tracking procedure.

45. As regards underwriting expenses, the Commission is concerned without current methodology used to apply these costs to the capital structure. In particular, the record in this case does not support the concept of applying current issuance costs uniformly across the common equity portion of the capital structure. It is evident that past issuance costs were a lower percentage of total proceeds than more recent issuance costs, hence to weight the common equity portion of the capital structure with a cost reflective of current issuance costs fails to consider past issuance costs

associated with previous issues. Furthermore, because the cost of issuing stock is often a known and measurable current expense, the Commission will consider the option of amortizing this expense directly (rather than considering it as one component of the cost of equity) in future rate cases.

Rate of Return

46. . Given common equity costs of 13.5 percent the Company's overall rate of return is 10.70 percent calculated as follows:

Weighted Cost of Capital

	Amount (000's)	Ratio	Cost	Weighted Costs
Long-Term Debt	$ 61,189	39.17%	8.50%	3.33%
Preferred Stock	22,994	14.72	7.791	1.15
Common Equity	72.046	46.11	13.500	6.22
	$156,229	100.00%		10.70

47. The 10.70 percent overall cost of capital is by any standards within any "range of reasonableness" concepts when compared with -- the Company's-requested overall rate of return of 10.639 percent;

COST OF SERVICE/RATE BASE.

48. There are several adjustments proposed by. Montana Consumer Counsel witness Hess to the Applicant's adjusted revenues, expenses and rate base. These include:

A. An adjustment for year-end rate base. The Applicant has proposed and presented exhibits based on use of a year-end rate base rather than an average year rate base. In his prefiled testimony Mr. Hess discusses the shortcomings in using a year-end rate base:

To achieve a proper matching of operating income for a 12-month test period with the investment that produced that income, the rate base to which the income is related must be the average rate base during the 12 months the income was earned rather than the rate base at the end of the Year.

Although the Company attempted to synchronize income with rate base by adjusting revenues and expenses to the year-end levels, there are two short comings to that approach. First, adjustments to revenues and expenses which attempt to restate operating income to that which would be produced if the year-end level of operations had continued for a full year, are- necessarily speculative. Second, even if such adjustments were not speculative, that approach fixes upon- revenues, . expenses and rate base relationships as of a single date which might not be representative of the longer term relationships such as those experienced for an entire year. (Hess, Direct, pp. 3,4)

The Commission finds the argument for an average-year rate base compelling and accepts. Mr. Hess' adjustment restating rate base - to an average year level.

B. The inflation adjustment. Mr. Hess also makes an adjustment-to back out the Applicant's 6.654 percent catchall inflation adjustment arguing that the adjustment " . is not based on specific identified known and measurable changes." (Hess, Prefiled, p. 5). The Commission, as it did in MDU's last two general rate cases, Docket Nos. 6567 and 6695, acknowledges the impropriety of the catchall inflation adjustment and accepts Mr. Hess' adjustment.

C. The royalty adjustment. As the Applicant's witness Mr; Da\rid P. Price has stated, the Applicant, on December 23, 1980, paid to the State of Montana $318,751 in settlement of a demand by the State for additional royalties on natural gas for the period from 1972 through October, 1980. The amount of the settlement allocated to the Company's Montana gas operations is $106,881 (per line 1, page 1, Schedule H-10 of MDU Exhibit No. 19). The total royalty adjustment consists of two parts: amortization of the amount and the proper paid past due amount, and payment of the current portion.

The appropriate amortization period for the past due amount and the proper price to be applied in calculating the current portion are contested issues in this case. MCC witness Hess has recommended a five-year amortization period and use of September, 1980 prices. The Applicant has suggested use of a two-year amortization period and January, 1981 prices.

The Commission accepts the Applicant's position on these issues. In that the amount to be amortized is not that significant and because a two year amortization period is consistent with the Commission's opinion regarding the amortization of excess deferred taxes in Finding of Fact No. 52 following, the two-year amortization period is appropriate. As regards price, the January, 1981 NGPA gas prices are a known and measurable change and, hence, accepted by the Commission. The total royalty adjustment is found to be $67,302.

D. Pension expense adjustment. In an uncontested adjustment Mr. Hess restates the 1979 test year pension expense to reflect a revised estimate of pension expense from the Company's actuary obtained subsequent to the preparation of its exhibit in this case. The Commission accepts this adjustment.

E. Income tax effect of revising pro forma interest expense. The Applicant has computed pro forma interest expense using year-end rate base adjusted for additions to storage gas in 1980 and Mr. Renner's weighted cost of debt. As Mr. Hess points out in his prefiled testimony, an adjustment is necessary to reflect average-year rate base (Hess, Direct, p. 6). Furthermore, the Applicant's adjustment to non-current gas in underground storage is no longer justified in light of consummation of the Frontier Gas Storage Project. Finally, the appropriate weighted cost of debt capital is 3.33 percent as found in Finding of Fact No. 46. Using witness Hess' average-year rate base before considering the Frontier transaction and the found weighted cost of deb-t, the Commission finds the correct income tax effect adjustment reflecting the revised pro forma interest expense to be $170,000.

F. Allowance for the amortization of pre-1974 profit on debt reacquired at a discount. Mr. Hess has made an adjustment to provide for an allowance for the amortization of pre-1974 profit on debt reacquired at a discount. As he explains in his prefiled testimony:

Prior to 1974 MDU flowed the gain on reacquired debt directly to earned surplus. In 1974 MDU began crediting Account 257 Unamortized Gain on Reacquired Debt with the profits and amortizing the profits over the life of the bonds. I understand that Dr. Smith w~ll take into account the profits on reacquired debt as they appear on the Company's books, but that does not include profits realized prior to 1974. Consequently, I have followed the procedure adopted by this Commission in MDU's prior rate cases, and added the amortization of such profits to the utility operating income. (Hess, Direct, pp. 16, 17)

The Commission finds this procedure appropriate and accepts the adjustment.

Tax Issues

Amortization of Excess Deferred Taxes. MCC witnesses Hess and Wilson have addressed the- issue of amortizing excess balances in deferred tax accounts that result as a consequence of a reduction in the federal corporation income tax rate from 48 percent to 46 percent. in January. of 1979. Witness Hess has calculated the excess amount associated with liberalized depreciation techniques to be $345,000 and the- excess amount associated with certain exploration costs to be $79, 000, and recommends a five-year amortization period in which to return the accumulated excesses.

Witness Wilson has determined the excess for the gas utility to; be $130,000. He suggests that the refund should equal the amount of revenues required from ratepayers necessary to fund the excess amount and calculates that amount to be

$240,000. Dr. Wilson recommends a two-year amortization period.

50. Applicant's witness Kolbe has argued that such an adjustment would violate Treasury Regulations Section 1.167(13-1(h)(2)(i). Mr, Kolbe contends that:

> In the absence of more specific provisions in either the Regulations or Rulings of the Internal Revenue Service, .the most reasonable interpretation of Regulations Section 1.167(1)-1(h)(2)(i), and that followed by the Company, is that the deferred tax reserve is reduced in any taxable year by reference to the tax rates applicable in such taxable year, regardless of whether such rates are higher or lower than the rates in effect for .the year when the reserve was created. If there is some amount remaining in the reserve account at the end of the useful life of the property or at the time of its retirement, a final adjustment to the reserve account would then be authorized by Regulations Section 1.167(1)-1(h)(2)(i). (Kolbe, Rebuttal, pp. 14,15)

51. The Commission does not find Mr. Kolbe's argument persuasive. In the absence of more specific provisions or subsequent IRS rulings on the matter, it is within the purview of the alternative regulatory agencies, i.e., state regulatory commissions, to address the issue and rule on the basis of that governing body's interpretation of the regulations. . This Commission, having decided in previous dockets (i.e., Docket Nos.6701 and 80.4.2) the appropriateness of allowing the amortization of the excess in deferred taxes resulting from the January, 1979 change in the corporate tax rate, finds no reason in the current case to alter its past decisions as regards this issue and accepts the adjustment proposed by MCC witnesses Hess and Wilson.

52. To wait until the end of the useful life of the property to allocate any balance

remaining in the account, as Mr. Kolbe suggests, would only tend to reimburse ratepayers who would not have shared in the funding of that account. It is the opinion of the Commission that the excess balance should be refunded in a reasonably short period of time. Consistent with pas-t decisions, the appropriate amortization period is found to be two years. The balance to be refunded is that found by Mr. Hess of $a~24,000. The adjustment in this docket is to reduce operating expenses by $65, 700; the reduction in required revenues is $130,540.

53. Deferred Tax (Full) Normalization. MCC witnesses Hess and Wilson have also advocated use of "full normalization" in accounting for deferred taxes arising as a consequence of using liberalized depreciation techniques for tax purposes while using straight-line depreciation to establish cost of service for ratemaking-purposes.

Traditional regulatory practices recognize the deferral of taxes collected in excess of taxes actually paid, but as Dr. Wilson explains failure to recognize full normalization may result in an inequity to current ratepayers. Dr. Wilson begins his argument by defining full normalization:

Full normalization with respect to deferred taxes consists of adjustments to tax expenses for ratemaking purposes so that those deferred taxes which are not paid currently are reflected as if they were a current expense on the income statement and as an addition to the deferred tax reserve on the balance sheet. Also, taxes currently attributable to the taxable income from which the deferred tax reserve addition was obtained are deducted from current revenue on the income statement and a corresponding non-cash income allowance for taxes on deferred credits (AFTDC) is recorded as a deferred charge on the balance sheet. (Wilson, Direct, pp. 13, 14)

54. Continuing, Dr. Wilson argues that under full normalization the future ratepayers who derive the benefit from the deferred account should also pay for the tax expenses associated with its creation. When asked to explain the tax expense associated with establishing the deferred tax reserve.

Dr. Wilson responds as follows:

- Deferred taxes result from the Company's allowed use of accelerated depreciation for tax purposes together with straight-line depreciation for ratemaking purposes. As a result of using accelerated depreciation for tax purposes, the Company obtains a larger current depreciation expense offset to taxable income than the actual depreciation expense which it incurs on its utility books of account.

This added depreciation expense- offset, however,. is a credit to before-tax income rather than being a pure tax credit. Therefore, at prevailing corporate tax rates, considerably more than one dollar must be collected from ratepayers in order to achieve a one dollar credit for deferred taxes. For example, at a 46 percent marginal income tax rate, an after-tax addition -of one dollar - to the deferred tax account requires that $1. 85 of before-tax revenues be collected from current ratepayers. This $1.85 of revenues is necessary to (a) pay taxes and (b) fund the one dollar after-tax addition to the accumulated deferred tax account. (Wilson Direct, c. 15)

To elaborate, one of the more unfortunate effects of collecting phantom taxes through utility rates is that, for each dollar of phantom tax expense allowed as a regulatory operating expense, a utility company's customers pay approximately two dollars of revenues; one dollar for the phantom tax and one- dollar for the current tax liability associated with the phantom tax (i. e., phantom tax dollars, since they have no current-expense offset, are taxable income as far as the IRS is concerned) . This doubling effect occurs, because, unlike real expenses, "deferred" taxes, which do not actually involve a current tax payment, are not a deductible expense for income tax purposes. In other words, the IRS recognizes these deferred tax dollars as income -not as tax expense. (Wilson, Direct, pp. 16, 17)

55. Dr. Wilson continues to point out a second problem associated with
not recognizing full normalization:

A second related over collection occurs where, as here, utilities continue to charge depreciation on plant financed with deferred tax dollars, even though the legitimate purpose of depreciation is only to repay the original investor for his own capital contribution. Because the investor of deferred taxes is the ratepayer, no depreciation expense is necessary to compensate utility company stockholders or bondholders for' this capital.

Under full normalization, in addition to deducting the deferred tax account from the rate base, the revenue collected in order to pay taxes on the tax reserve accrual should be treated as a deferred charge, and there should be a depreciation expense adjustment to recognize that portion of plant that was purchased with customer contributed deferred tax dollars. (Wilson, Direct, p. 17)

56. As regards equity, Dr. Wilson concludes that:

. . . there is a major inconsistency and a fundamental inequity inherent in the Company's proposal. That is, MDU defers the current tax reduction associated with accelerated depreciation, but currently expenses the additional tax liability associated with the accumulation of deferred taxes. An even-handed and comprehensive inter-period tax allocation approach would require that both the benefits and the costs associated with tax deferrals be normalized. To normalize only the benefits, through the process of including deferred tax expenses in the test-year cost of service, while flowing through the associated current tax expense, rather than normalizing such costs, is unfair to current ratepayers. (Wilson, Direct, p . 19)

57. Dr. Wilson concludes with a recommendation as to the proper adjustment required for consistency with full normalization:

There should be an adjustment to the cost of service which defers the current tax costs associated with the provision for deferred tax benefits to those future periods when future ratepayers will ultimately benefit from the availability of dollars accumulated in the deferred tax account. I suggest that this be done by treating those current income taxes that are associated with the accumulation of deferred tax credits as a deferred charge, thus permitting a reduction in current revenue requirements to be offset by a reduction in current tax. liability and an Allowance For Taxes on Deferred Charges (AFTDC) as non-cash, other income for ratemaking purposes. Correspondingly, since ratepayers do receive some benefit from the deduction of accumulated deferred taxes from rate base for ratemaking purposes, I believe that, if this approach is adopted, it would be consistent to-make a rate base addition for the accumulated deferred tax charges. (Wilson, Direct, pp. 20, 21)

As shown on Exhibit (J. W. -2), the Company's gas utility operating revenue requirement for ratemaking purposes should be reduced by $348,852, and AFTDC income of' $188,381 should be recognized . ' If this is done, and an allowance for the carrying cost of the deferred charges (about $20,000) is added back to the revenue requirement, there will be a substantial revenue reduction for current customers, and net income, including non-cash item's, will remain unchanged. (Wilson, Direct, p . 22)

58. The Applicant has sponsored the testimony of Mr. K. William Kolbe on the issue of full normalization. Mr. Kolbe argues that use of full normalization does not comport with Treasury Regulations and, hence, jeopardizes ' tine' Company's capability to use liberalized depreciation methods.

Mr. Kolbe's contention is grounded ' specifically in Treasury Regulations Section 1.167(1)-1(h)(1)(i)(b), which provides as follows:

If to compute its allowance for depreciation under section 167 it [the taxpayer] uses a method of depreciation other than the method it used for purposes described in (a) of this subdivision, the taxpayer makes adjustments consistent with subparagraph 2 of this paragraph to a reserve to reflect the total <u>amount</u> of <u>the deferral</u> of <u>federal income</u> tax <u>liability</u> resulting from the use with respect to all of its public utility property of such different methods of depreciation. (Emphasis supplied)

And Treasury Regulations Section 1.167(1)-1(h)(2)(i):

Adjustments to reserve. (i) The taxpayer must credit the amount of deferred Federal income tax determined under subparagraph (1)(i) of this paragraph for any taxable year to a reserve for deferred taxes, a depreciation reserve, or other reserve account. The taxpayer need not establish a separate reserve account for such amount but the amount of deferred tax determined under subparagraph (1)(i) of this paragraph must be accounted for in such a manner so as to be readily identifiable. With respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any tax year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation under subparagraph (1)(i) of this paragraph. An additional exception is that the aggregate amount allocable to deferred tax under section 167(1) may be properly adjusted to reflect asset retirements or the expiration of the period for depreciation used in determining the allowance for depreciation under section 167(1). (Emphasis supplied)

60. Mr. Kolbe interprets the cited Sections as follows:

These regulations make it clear that the amount credited to the reserve must be the total amount of the deferral of federal income tax liability resulting from the use of accelerated depreciation. Furthermore, such amount credited to the reserve shall not be reduced, except as permitted by Regulations Section 1.167(1)-1(h)(2)(i). The only permitted reductions to the reserve accounts are amounts which reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of accelerated depreciation and adjustments to reflect asset retirements or the expiration of depreciable lives. Any other adjustment which has the effect of reducing the amount allocable. to deferred tax under Code Section 167(1) would violate this regulation. Consequently, the taxpayer would no longer be treated as using a normalization method of accounting. The ultimate result would be that accelerated depreciation could not be deducted for federal income tax purposes. The taxpayer would be permitted to use only a straight-line method of depreciation for tax purposes as provided by Code Section 167(1)(2)(A). (Kolbe, Rebuttal, pp. 8, 9)

61. Mr. Kolbe acknowledges that the procedure recommended by MCC

witnesses Hess and Wilson does not directly reduce the deferred income tax credit account (Kolbe, Rebuttal, p. 9, Tr. p. 230). The essence of his argument lies with the effect of the procedure, which he asserts is to indirectly reduce the deferred income tax credit account through use of the deferred debit account (i. e., Dr. Wilson's proposed Allowance for Taxes on Deferred Credits - AFTDC - account).

62. It has long been the general policy of regulatory commissions to align, to as practical an extent as possible, the costs associated with the benefits derived by ratepayers with those same ratepayers. From this point of view the full normalization concept is appealing. On the other hand, the Commission in no way wishes to jeopardize the Company's ability to utilize liberalized depreciation methods. In line with this latter consideration, MCC witness Hess expresses the following caveat in his prefiled- testimony:

I would not recommend an adjustment that would jeopardize the availability of liberalized depreciation to the company. Therefore, I suggest that the commission make this adjustment conditional on receiving a ruling from the IRS that the adjustment does not disqualify the utility for continued use of liberalized depreciation. (Hess, Direct, pp. 11, 12)

63. The Commission, in its uncertainty as to the effect of the adjustment in terms of Treasury Regulations, directs the Applicant to seek a ruling on this matter within three months from the service date of the order.
If a favorable ruling is received on the use of full normalization, the adjustment proposed by Mr. Hess will be accepted and the revenues associated with full normalization will be refunded to the customers with interest at the rate of 10 percent. Should no revenue ruling be received from the IRS within two years from the service date of this order the Commission will give serious consideration to the adoption of full normalization without a revenue ruling.

64. The Commission finds the following results of operations for MDU's gas utility:

MONTANA-DAKOTA UTILITIES COMPANY
GAS UTILITY - MONTANA
RESULTS OF OPERATIONS
1979 TEST YEAR
(000 ' s)

	Per Book (A)	Company Adjustments (B)	Adjusted Per Company (C)	Commission Adjustments (D)	Adjusted (E)
Operating Revenue	$33,088	$ 3,139	$36,227	$ (285)	$35,942
O & M Expenses					
Cost of Gas	$93,879	$(4,853)	$19,026	(155)	$18,871
Other	8,542	1,447	9,989	(233)	9,756
Total	$32,421	$(3,406)	$29,015	(388)	$28,697
Depreciation and Depletion	1,593	89	1,682	(89)	1,593
Taxes other than Income 924 48 972					
Federal and State Income Taxes					
Current	(3,485)	2,881	(604)	271	(333)
Deferred	1,317		1,317		1,317
Investment Tax Credits	411		411		411
Amortization of Investment Tax Credits	(22)		(22)		(22)
Amortization of Excess Deferred Taxes -				(66)	(66)
Current Taxes on Deferred Income -					
Total Operating Expenses	$33,159	$ (388)	$32,771	(272)	$32,499
Operating Income	$ (71)	$ 3,572	$ 3,456	(13)	$ 3,443
Amortization of pre 1974 Profit on Debt Reacquired at Discount				16	16
Total Available for Return	$ (71)	$ 3,572	$ 3,456		$ 3,459
Rate Base	$43,139	$10,716	$53,855	$(2,773)	$51,082
Rate of Return	(0.17%)		6.42%		6.77%

Effects of Implementing the Frontier Storage Project

65. On March 10, 1981 this Commission signed Order No. 4753

in Docket No. 80.9.74. The order gave authority to MDU to enter into a transaction for the purpose of financing the acquisition and storage of natural gas via the Frontier Storage Project. MDU, having received the requisite regulatory approvals, has subsequently entered into the transaction. The implications of the transaction have a significant impact on the present matter in that the transaction provides for the sale of that quantity of gas in underground storage in excess of the December 31, 1978 level. Consequently, the Company's rate base is substantially reduced, which in turn results in a substantial reduction in the Company's revenue requirements.

66. Consumer Counsel witness Hess and Applicants witness Ball agree on the Company's rate base in light of the Frontier transaction. (Tr., p. 256 and Tr. p. 374). The storage project- reduces the Company's rate base in Montana to $38,453,000. The reduction in rate base produces a concomitant reduction in the total amount available for return due to the interest deduction (increase in tax expense) associated with the rate base reduction. At the approved rate of return this results in a return deficiency of $863.000. which translates into a revenue - deficiency of $1,714,000. These figures are derived as follows:

MONTANA-DAKOTA UTILITIES COMPANY
GAS UTILITY - MONTANA
REVENUE DEFICIENCY
1979 TEST YEAR
(OOO's)

1. Gas Utility Rate Base	$38,453
2. Recommended Rate of Return	10.7%
3. Recommended Return	4,114
4. Total Available for Return	3,251
5. Return Deficiency	863
6. Revenue Deficiency	1,714*

See Finding No. 75

Rate Design

67. Findings of Fact No. 39, 43, 44 and 45 of Order No. 4635 in Docket No. 6695, MDU=s last general rate case, set forth the principal elements of the volumetric pricing structure adopted by this Commission in that case. Those findings provided for an inverted block rate structure with an initial block of 15 Mcf's during the months of December through March priced at a 25 percent discount in all schedules- covering firm sales. Remaining Mcf's were to be priced volumetrically at the level necessitated by the revenue requirement, giving due consideration to the interruptible rate differential sanctioned in Finding of Fact No. 39

68. No evidence was presented in the current matter indicating that a change in the general nature of the existing rate structure is appropriate. However, MCC witness Wilson has argued that it is no longer appropriate to not charge industrial customers for storage costs. (Wilson, Direct, p.36) Referencing Consumer Counsel Data Request No. Company has forecast no curtailments for 1980/1981.

69. Furthermore, Applicant's witness Schuchart has indicated that the Company intends to eliminate the FERC approved Curtailment Program that in the past has placed limitations on the quantity of gas available to large industrial users:

Q. Mr. Schuchart, in previous rate hearings, the Montana-Dakota Utilities Co. Curtailment Program has been discussed. I believe in December there was some testimony as to a study that you were conducting as to
whether or not it should be dispensed with. Do you have anything at this time to tell the Commission concerning the Curtailment Program?

A. Yes, I think two things. First, the volumes of gas available to those industrial customers affected by the Curtailment Plan have been increased so that the total volumes that they are entitled to under the contract are not reverting back to the base-period volumes established some years ago. Put another way, those customers are no longer being curtailed.

Secondly, - the Company has contacted all of the industrial customers who were party to -- who were a party to the settlement agreement in the Curtailment Plan requesting their support of MDU's efforts to lift or eliminate the Curtailment Plan. And . that process is ongoing. We have not received the concurrence and consent of the industrial customer.

Q. So it's the intention of the Company at this time to eliminate the Curtailment Program altogether?

A. Yes. (Tr., pp. 16,17)

And furthermore, while under cross-examination to Mr. Anderson, counsel acting on behalf of intervenor Pierce Packing Co., et al., Mr. Schuchart continued to state:

Q. Certain [industrial users] obtained through data committees and one thing and another an agreed volume of gas which your Company agreed to give to them. What assurance will your Company give them that they will continue to have that gas available in the future, at least through the period of time that the present Curtailment Program runs?

A. Well, the same assurance they have now. We will continue to contractually agree to deliver a specified volume of gas to meet the customer's requirements. We'll do it by contract on an annual basis.

Q. Will you do it on a long-term basis that will protect them through at least the middle of 1983?

A. Oh, I would have no particular problem with a two-year contract. That's what you're talking about would be, in effect, a two-year contract. (Tr. pp. 18, 19)

70. The Commission finds it reasonable to assume that industrial customers will face no interruption of service during the period in which rates established in this proceeding will be in effect Continued service, especially on the MDU system, is dependent on the system's extensive underground storage facilities, particularly so in the winter heating system. Consequently, the Commission finds it reasonable that industrial users share in the cost of providing underground storage. Furthermore, the rate differential between industrial users and firm class users is no longer appropriate and should be discontinued. The justification for the differential, that industrials receive a less valuable service, no longer exists.

SUPPLY/DEMAND ISSUES

71. As regards supply/demand issues, of special concern to the Commission at this time is the Company's position in relation to excess deliver ability and take or requirements. It is clear from the evidence that the Company has contracted to take delivery of certain volumes of gas in excess of system market requirements plus storage capacity during the next several years. It is the Commission's understanding that this excess deliver ability is to be siphoned off in the form of off-system sales contracted at system incremental prices. It is the intention of this Commission to monitor the Company's supply/demand scenario with the express purpose of preventing any possibility of the Company entering a take or pay situation having the potential to adversely affect the welfare of the ratepayer. In this regard the Commission requests MDU to provide information as it becomes available pertaining to all negotiations for off-system sales, to include the filing of

any FERC tariffs necessary to make off-system sales.

72. Evidence exists on the record to indicate that should the Company for any reason be unable to find a buyer for the 10 Bcf of annual off-system sales it plans for the years 1986-1990 the likelihood of entering a take or pay situation increases:

Q. What is the factual basis of those predictions [that there will be a drain on storage beginning in 1985]?

A. We're basing them on the amount of gas we expect to get delivered from each source from which we buy gas, the amount of gas our customers will consume, the amount of gas we intend to sell to others.

Q. Will you incur take-or-pay penalties if you do not sell that 10 BCF after 1985?

A. We could possibly incur those penalties, yes. Currently, that's the reason we're being pressed to sell the volumes on the short-term basis because of the take-or-pay penalties in those contracts. (Tr. pp. 50,51)

73. In light of the above mentioned possibility of incurring take-or-pay penalties in the future, the Commission considers any negotiations involving 100 percent take-or-pay provisions to be questionable, whether they be past, present or future negotiations. The Commission recognizes, however, that much of the 100 percent take-or-pay contracting is connected with associated gas. In these situations the Company should use price as the relevant negotiating tool. If current market conditions result in excess deliver ability, the Company may be in a position to renegotiate the price paid for associated gas. Current NGPA prices set a maximum lawful level that can be paid for natural gas, not a mandatory level. As regards future negotiations not

involving associated gas, the Commission will very carefully scrutinize any contract involving 100 percent take-or-pay provisions. As regards future off-line sales, the Commission would heartily endorse any such sales made to the Montana Power Company and will, within reasonable limits, provide all possible assistance in facilitating such sales.

74. Finding of Fact No. 5 of Order No. 4742a in Docket No. 80.10.87, MDU's last tracking case, states that " . . . until such time as persuasive evidence to the contrary is presented the appropriate gas mix on which to base a tracking procedure is that mix last approved within the confines of a general rate case. Although the Company has shown the actual level of produced gas for 1979 to be 3, 631, 749 Mcf (Schedule G-10, Applicant's Exhibit No. 19), Applicant's exhibit referred to on page 49 of the transcript shows the estimated produced gas quantities for 1981 to be 6.4 Bcf . The Commission finds this latter figure to be the most appropriate level of produced gas on which to base the Company's future tracking applications.

COMMUNITY ENERGY MANAGEMENT

75. The Commission is impressed with the work being accomplished in Yellowstone County toward Community Energy Management, and wishes to reinforce the cooperative efforts by MDU's Energy Conservation Personnel. To further assist the community effort on an experimental basis the Commission is amenable to authorizing a direct contribution by MDU of up to $20,000 in support of a Community Energy Management effort The Commission views such a contribution as an important part of energy conservation and the development of localized energy sources in the state of Montana. The contribution is authorized only on the conditions that the effort have a broad based community based board of directors, be committed to the concept of replacing present levels of energy consumption with conservation, and energy

from local sources, including cogeneration, and be matched dollar for dollar by similar financial efforts from private, nonprofit, or state, local, and federal governmental sources. The Commission will closely review the outcome of this authorization before expanding the concept to other communities in the distribution area. The Company will be responsible for tracking and should at any time be able to account for the disposition of these funds. The contribution increases the Company's return deficiency to $883,000 and revenue deficiency to $1,734,000.

FILING CONSIDERATIONS

76. Finally, because the volumetric pricing methodology (based on marginal cost philosophy) is currently the most appropriate - pricing methodology comporting with conservation, efficiency and equity - considerations, the Commission no longer finds it suitable for the Applicant to submit cost of service studies based on traditional average embedded costs and utilizing the Seaboard or United formulas.- Obviously, the Company is free to make whatever case it finds appropriate; however, in future rate cases the Commission will very carefully scrutinize any expenditures made by the Applicant and claimed as a rate case expense for this type of study. The prudence of such expenditures seems dubious in light of the Commission's strong and clearly enunciated policy favoring a marginal cost methodology.

77. The above argument also extends to other areas of rate-making philosophy including year-end rate base, catchall inflation adjustments and CWIP in rate base. As with traditional cost of service studies, the Commission also is skeptical of the value of studies incorporating these rate-making philosophies. (The Commission notes that these issues consistently have been rejected in past rate cases without subsequently being overturned in the courts.) These issues will be carefully scrutinized in future filings and unless

accompanied by new arguments found to be extremely compelling and of substantial merit will be considered a nonproductive use of time. The policy of expending time and money to include CWIP in the Applicant's requested rate base is especially questionable in light of the Commission's conclusion that Montana's original cost statute precludes inclusion of CWIP in rate base. The greatest-scrutiny will be afforded to expenses associated with such proposals in future rate cases

CONCLUSIONS OF LAW

1. Applicant, Montana-Dakota Utilities Co., is a corporation providing natural gas services within the state of Montana and as such is a "public utility" within the meaning of Section 69-3-101, MCA.

2. The Montana Public Service Commission properly exercises jurisdiction over the Applicant's operations pursuant to Title 69, Chapter 3, MCA .

3. The rate base adopted herein reflects original cost depreciated values and as such complies with the requirements of Section 69-3-109, MCA, that the value placed upon a utility's property for ratemaking purposes "...may not exceed the original cost of the property."

4. The rate of return allowed meets the constitutional requirement that a public utility's return must be "commensurate with returns on investments in other enterprises having corresponding risks and sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attrack capital." Federal Power Commission v. hope Natural Gas Company, 320 U.S. 591, 603 (1944).

5. The Commission acts in its legislative capacity when it allocates utility costs to the various customer classes.

6. The objectives of conservation, efficiency and equity are promoted by the rate structure approved in this order.

7. The rate structures authorized by the Commission, based upon analysis of the entire record, are just, reasonable, and not unjustly discriminatory.

ORDER

1. The Montana-Dakota Utilities Company shall file rate schedules which reflect annual gas utility revenue increases of $1,734,000.

2. Rate schedules filed shall comport with all Commission determinations set forth in this order and in such manner so as to increase rates in accordance with the volumetric pricing methodology maintaining the 25 percent differential between winter discount and remainder of year rates.

3. All motions and objections not ruled upon are denied.

4. This order is effective for services rendered on and after April 27, 1981.

Done and dated this 27th day of April, 1981 by a vote of 4-0

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

Gordon E. Bollinger, Chairman

Thomas J. Schneider, Commissioner

Howard L. Ellis, Commissioner

John B. Driscoll, Commissioner

ATTEST

Madeline L. Cottrill
Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and procedure, esp .38.2.4806,ARM